Electric Transmission Infrastructure Expansion
Considering Property Value Impact on Routing

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Nowadays there is an increasing interest in the development of utility scale renewable generation, which is generally located far from load centers. As a consequence, there is an increasing need for developing electric transmission infrastructure between those remote areas and urban ones. These developments usually face social opposition, which produce permitting delays or even project cancellations. The magnitude of these perceptions can be quantified by using property value reductions as a proxy. The description of property value as a function of amenities is called hedonic price modeling, and in the case of transmission lines it has been found that distance to transmission towers and their visibility are its main drivers. It is important to notice that the quantification of property value reduction can be used not only as a penalization to avoid contention in transmission development, but can also be recognized as a cost incurred by society for placing transmission lines nearby to populated areas. Thus the development of new transmission lines has an investment capital cost and a social one, which in several cases have the same order of magnitude. This situation motivates revisiting the formulation of the traditional transmission expansion problem (TEP).

An MILP formulation is then presented that minimizes the capital and social cost produced by transmission lines, and generation costs to satisfy demand. The decision variables of the problem are the candidate lines selected to be constructed, the generation levels, and the route of transmission lines. In the formulation two networks are represented; the electrical and routing networks. The electrical network represents the electrical connectivity among the different elements in the power system (generators, transmission lines, etc.). The routing network represents by its edges the places under which a segment of transmission lines can be routed, and it is constructed from Geographical Information Systems (GIS) data. Both networks are intrinsically coupled by electric and cost related constraints.

Several special considerations make the proposed formulation and implementation suitable for real world applications. The first one has to be with the identification of constraint relaxations that allow decomposition of the original problem into one associated with the electrical network (investment decisions) and other with the routing network (transmission routing). The effectiveness of the relaxation of different constraints is analyzed. The second feature is the reduction of the routing network size, preserving its capability to represent different possible routing alternatives.

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Title: Using Allowance Allocation Methods to Prevent Emissions Leakage under the Clean Power Plan

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The United States formally ratified the Paris Agreement on September 3rd during the group of 20 nations’ meeting in China. The ability to fulfill its self-defined emissions reduction target of reducing emissions 26-28 percent below 2005 levels by 2025 hinges on designing fair and efficient carbon emissions regulations. The federal government announced the final rule of the Clean Power Plan in August 2015 as the major regulation for the electricity sector, the largest emitting sector in the United States. The rule imposes a bottom-up approach allowing states to adopt either a rate- or a mass-based program and to choose whether newly constructed sources are covered by the state plan or not. Two potential hazards to environmental integrity caused by these two choices are: 1) the emission leakage across jurisdictions due to different choices of rate and mass programs; and 2) the emission leakage from covered sources to uncovered emitting new sources. In previous RFF studies we examined the geographic leakage issue. In this study, we investigate emissions leakage from existing to new sources and the potential for different initial allowance allocation methods to provide production incentives to various generators to address this hazard.

We examine leakage using a highly parameterized capacity planning and operation model of US electricity markets — the Haiku electricity market model. We compare environmental and economic performance under different policy scenarios of initial allowance allocation methods. Key features of the model include all major environmental regulations affecting electricity supply in the US, new information about recently reduced renewables costs, and the extension of the production tax credit (PTC) and investment tax credit (ITC).

Some of the initial findings are:

- Updating output-based allocation (as opposed to grandfathering) tends to mitigate leakage, when focused on existing natural gas generators
- Expanding eligibility to earn allowances to all affected sources (including coal fired generators along with gas generators) is almost as effective
- Allocating to new renewables has relatively little effect in reducing leakage
- Updating output-based allocation to all affected sources helps reduce the regional differences in the allocation rates and in the production incentives to natural gas across jurisdictions. Assigning states a fixed allocation rate is another remedy to regional differences
- More stringent emissions targets (90% of the existing EPA-set state targets) tend to increase the allowance price, which increases the production incentives to various technologies

Our initial explanation for the findings listed above relates to the various levels of production incentives created by the initial allocation to different emitting sources. Whilst no single allowance allocation scheme can solve the emissions leakage, an updating output-based allocation can mitigate it substantially.
Dynamic Pricing and Demand Response in Electricity Networks Serving Smart Communities
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Abstract
It has long been agreed upon by the practitioners and researchers in the field of electric power market operations that both pricing and demand must play much more proactive roles in better balancing demands across the hours of the day. A balanced system will mitigate demand and price spikes and thereby reduce the need for expensive reserve generation capacity as well. Balanced demand will also mean increased network reliability. However, proactive management of pricing and demand would require a more upgraded power market infrastructure than what is currently in place in the U.S. Fortunately, increasing availability of advanced metering and power network infrastructure supported by the Internet of energy (IoE) will soon pave the way for the desired upgrade. This will facilitate dynamic pricing of electricity by system operators and intelligent demand response by load schedulers (controllers) in smart and connected consumer communities. A dynamic pricing strategy will offer binding prices for each time interval (perhaps, hourly) to the consumer nodes before loads are scheduled. In response to dynamic pricing, the smart communities will optimize their load schedule for all remaining time intervals of the day, as well as manage the use of renewable power generated by the communities.

Dynamic pricing and demand response (DP&DR) in a network will be highly interdependent between actions of the system operator and the community controllers. The dynamic pricing goal for the nonprofit system operator will be to minimize variations between payment received from the consumers and payment made to the generators. The demand response goal will be to minimize the cost of electricity to their communities over a 24 hour period. DP&DR, as described above, have not yet been adopted in power network operations anywhere in the U.S. In this talk, we present a model designed to obtain dynamic pricing strategies as well as intelligent demand response strategies that work together to reduce cost to the consumers and reduces demand and price spikes. Results from a sample numerical problem are discussed.
The current practice of discrete-time electricity pricing starts to fall short in providing an accurate economic signal reflecting the continuous-time variations of load and generation schedule in power systems. This presentation will introduce the fundamental mathematical theory of continuous-time marginal electricity pricing. We first formulate the continuous-time unit commitment (UC) problem as a constrained variational problem, and subsequently define the continuous-time economic dispatch (ED) problem where the binary commitment variables are fixed to their optimal values. We then prove that the continuous-time marginal electricity price equals to the Lagrange multiplier of the variational power balance constraint in the continuous-time ED problem. The proposed continuous-time marginal price is not only dependent to the incremental generation cost rate, but also to the incremental ramping cost rate of the units, thus embedding the ramping costs in calculation of the marginal electricity price. Using the numerical results, we demonstrate that the continuous-time marginal price manifests the behavior of the constantly varying load and generation schedule in power systems.
Sensitivity and covariance in a large-scale  
Stochastic Complementarity problem using first  
order approximation  

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Abstract  
We provide an efficient method to estimate the covariance between  
decisions variables in a solution of a general class of stochastic nonliner  
complementarity problems. We use first-order Taylor approximation  
methods to approximate the decision variables due to a perturbation in  
the random parameters. Then we estimate the covariance between the  
decision variables due to the random perturbation. We also develop a  
sensitivity metric to determine the change in the variance of the output  
due to a change in the variance of an input parameter, which helps in  
determining the parameter which we would like to know with the greatest  
certainty. Having done this, we extend the deterministic version of the  
North American Natural Gas Model (NANGAM), to incorporate effects  
due to uncertainty in the parameters of the demand function, supply func- 
tion, infrastructure, and investment costs. We use the sensitivity metrics  
to understand the quantities that impact the equilibrium the most.

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Modeling competitive equilibrium prices for energy and balancing capacity in electricity markets involving non-convexities

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Abstract

In economic analyses of markets often the dual variables of market clearing equations derived from the optimal solution of cost-benefit optimization models are interpreted as efficient market prices. Whereas in convex (linear) problem formulations the validity of this approach is undisputed it cannot be generalized to problem formulations containing non-convexities (indivisibilities). The withholding of spinning reserves in electricity markets are a good example of such cases as costs in these markets are essentially driven by indivisibilities stemming from technical constraints of generation units.

In this paper we present a novel modeling approach designed to find equilibria in binary games to derive equilibrium prices of self-committed electricity market models and discuss how the results differ from the ones of centrally committed markets. In particular, we study the pricing of spinning capacity reserves used to balance the power system and compare welfare implications and allocational efficiency between the binary-equilibrium approach and a central-planner model.

Keywords: Balancing Electricity Markets, Competitive Equilibrium Prices, Non-Convexities, Binary Games, Discrete Optimization

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Generating Unit Retirements and New Capacity Needs Under Three Market Structures**

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In this presentation we present simulated paths of coal-fired power plant (CFPP) retirements under three market structures: regulated monopoly, variable cost dispatch market, and an alternative market designed to reduce cycling damages to CFPPs. The simulations of electricity market generation, retirements and new capacity requirements are performed using Argonne’s Electricity Supply and Investment Model (ESIM).

Cycling damage is mostly due to the interaction of creep (time-dependent deformation below tensile yield) and fatigue (defect growth from cycling-induced changes in stress) associated with CFPP load following (and/or starting and stopping) [1-3].

Currently low gas prices and renewable mandates and subsidies have already resulted in capacity factor reductions for existing CFPPs. These older plants were not designed for cycling operations. Further, we find that adding a CO2 price (or CO2 regulations which induce a shadow price on CO2 emissions) would result in dramatically increasing cycling damage and attendant CFPP retirements, and possible doubling of gas-fired power generation. The rapid retirement process is partly driven by cycling operations causing increased heat rates and other O&M costs and further pushing existing CFPPs down the dispatch order, accelerating their retirement. This process has been elaborated within a recent Stanford University Energy Modeling Forum (EMF-31) study [3].

In the variable cost dispatch market simulations, cycling damage and associated maintenance and capacity replacement costs are the highest. In the regulated monopoly, net present value costs are the lowest (monopoly profit maximization implies cost minimization), although electricity prices may be higher. There are a number of alternative market designs that could potentially reduce costs of generating electricity with measures that mitigate cycling damages. Measures could involve including cycling damage into dispatch costs. The design could also employ dispatch rules that limit the amount of severe load following operation for a CFPP, particularly for units which are deemed important to maintain for market reliability and resiliency. Here we present system simulations of these alternatives.

**Donald Hanson and David Schmalzer appreciate the support from the National Energy Technology Laboratory. The work described here does not necessarily reflect the views of Argonne National Laboratory, the University of Chicago, the National Energy Technology Laboratory, or the U.S. Department of Energy. Argonne National Laboratory’s work was supported by the U.S. Department of Energy, Office of Fossil Energy under contact DE-AC02-06CH11357.

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Abstract: Why has OPEC not decided to cut their production in the wake of 2014’s price fall, and which role does competition play in the crude oil market? Numerous studies have tried to answer these questions during the last years with explanations pointing in three main directions: (1) OPEC has tried to defend its market share against expanding US shale oil by flooding the market in an attempt to drive out shale producers; or (2) the overwhelming shale oil revolution has nullified OPEC’s market power and left its members with no decision but to accept low prices; or, lastly, (3) OPEC might have been uncertain regarding shale oil potential and needed to test its performance under low prices. However, these works are mostly qualitative or provide only little insight into market mechanisms (most importantly, Baumeister and Kilian (2016), Fattouh et al. (2016), Dale (2016), Baffes et al. (2015), Aguilera and Radetzki (2015), Behar and Ritz (2016)).

This study aims at aiding the discussion with quantitative evidence from computational equilibrium modelling. I set up a model with quarterly partial equilibria Q4 2011 – Q4 2015 from present short-term profit maximisation a la Huppmann (2013) and examine the ability of different setups in explaining actual market outcomes over periods covered. Although the models (in particular a Stackelberg formulation with Saudi Arabia preceding a competitive fringe) perform reasonably well during the initial periods of high prices, all models fail to capture the drop in prices post-2014, and prices fall even beyond perfect competition. Rejecting present short-term profit maximisation as the governing decision rule in combination with a qualitative discussion of Saudi Arabian politics and the shale oil revolution leads to the conclusion that the price drop of 2014-15 was most probably the result of an attempt to defend market shares and to test for the supply elasticity of shale oil. Thus, current attempts to reach a new deal on multilateral cuts on crude oil production are the result of shale oil being more robust than expected in the light of increasing fiscal pressure on OPEC economies, despite partial success in reducing the number of US rigs. A counterfactual modelling scenario of a united OPEC explains that coordination to high prices is virtually impossible without an infeasible, individual Saudi production cut of approximately 80%, which is one of the reasons why OPEC struggles to introduce unilateral cuts.

Selected References:

Efficient market design for short-term power markets with inflexible units

Abstract for the TAI 2016

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Overview

The paper investigates alternative market design choices in the presence of larger intraday uncertainties such as renewable forecast errors. The focus is thereby on analytical solutions in continuous probability space in a stylized market environment. The paper therefore develops a stylized model incorporating the following key assumptions: intermittent supply uncertainty, binding day-ahead unit-commitment decisions, no grid congestions, competitive markets, continuous spectrum of producers with flexibility constraints. This approach is used to compare the following configurations:

- Self-scheduling & auction-based day-ahead market with expected-values based schedule (current German market)
- Self-scheduling & auction-based day-ahead market with arbitrage freeness in expectations
- System dispatch with expected-values based schedule
- System dispatch with arbitrage freeness in expectations (including financial players, current PJM market)
- Full stochastic system dispatch solution

Without inflexibilities in the unit commitment, the design of the day-ahead market would be largely irrelevant for actual system operation since plant and/or system operators could unwind day-ahead decisions fully in real time when uncertainties have been resolved. Yet with (partly) irreversible unit commitment, the market design may induce inefficient choices of market participants respectively the system operator.

Methods

The model considers two markets: day-ahead and real-time (corresponding to intraday market in Europe). In order to investigate the impact of start-up costs as well as minimum operation or minimum shut down times, two delivery periods are considered (may be generalised later). Three types of generation are included: 1) intermittent generation with uncertain production and zero or negative variable costs (negative variable costs arising from subsidies), 2) base load generation which is modelled as inflexible with low variable costs 3) peakers which are flexible but have high variable costs. Besides the output dependent variable costs, start-up costs are included and variable costs within one generation type are approximated by a piece-wise linear marginal cost curve.

Results

It is shown in a first step that the unit commitment and dispatch based on (day-ahead) expected values will in general not lead to the same day-ahead unit commitment than the full stochastic approach. Hence it is prone to inefficiency. Thereby the analysis focuses on the case were both the inflexibility between delivery periods and the short-term inflexibility are so large that the capacity of the base load technology has to be set on the day-ahead market identically for both time slices and remains fixed also for real time. Further investigations will show whether both the self-scheduling and the system dispatch with arbitrage-free bids are capable to replicate the full stochastic solution and whether the revenue streams for the market participants are equivalent. In particular, it is investigated, what effect financial players submitting virtual bids and requesting a higher return on their risk capital have on the market equilibrium.

References

**Title:** A Framework for Modelling Residential Prosumption Devices and Electricity Tariffs for Residential Demand Response  

**Author Names:** Marc Beaudin* (Johns Hopkins University), Hamidreza Zareipour (University of Calgary), Anthony Schellenberg (University of Calgary)  

**Presentation or paper due dates coming soon:** The paper was submitted to IEEE Transactions on Smart Grids, and retracted due to formatting issues (they do not accept 2-part papers anymore), so the content will be organized and re-submitted by the end of 2016.

**Abstract:** The objective of this work is to provide a flexible modelling framework for including electricity tariff structures and energy prosumption devices in optimal energy management systems for the residential sector. An energy prosumption device could either be one that consumes electricity (e.g., a refrigerator) or one that produces electricity (e.g., a rooftop solar panel). In our work, the home energy management system (HEMS) optimizes electrical and heat flow in a dwelling to improve the customer’s objective, as well as ensuring that an electric vehicle is properly charged when the need for transportation arises.

The utility industry has offered residential consumers various electricity tariff structures in order to better reflect their contribution to the cost of electricity production, and to give incentives to consumers to improve their load profile through demand response. For example, in Ontario, Canada, residential electricity customers are billed on a time-of-use plan, where the cost of electricity cycles according to the time of day. Alternatives to changing the price structure also exist, such as Incentive Based Programs, which include direct load control, interruptible or curtailable programs, demand bidding, emergency demand response, capacity markets, and ancillary services market. However, electricity is a commodity with a high value compared to its price, which results in a low will to change consumption. This is evidenced by the high value of residential load, up to 16 $/kWh, to electricity cost, in the range of 0.1 $/kWh. Thus, elasticity is unless the price of electricity is high, such as during a critical peak pricing period. However, willingness to respond may improve if the prosumption of some devices were automated.

We review and discuss existing electricity tariff structures in the context of optimal scheduling of HEMSs, and provide a new modelling framework for scheduling prosumption by partitioning tariffs into pricing components, such that a combination of various pricing components form electricity tariffs. Additionally, we present general models for residential devices by binning the devices into limited response classes, based on the diverse residential device models and descriptions reviewed in the literature. By using this modelling framework, devices, pricing components, and response classes can be added or removed while maintaining the integrity of the model structure. The components of the model are linearized as much as possible without affecting the integrity of the results. Mixed Integer Linear Programming (MILP) models are presented when Linear Programming (LP) models cannot accurately capture the behaviour of tariffs and loads. Using the model, we create a set of 21 revenue-neutral electricity tariff structures, and we illustrate how a dwelling responds to different price signals in order to evaluate the demand response performance of the dwelling. Numerical results show that time-of-use inclining block rates, and daily peak demand charges achieve the most desirable results for the retail operator.

There are three contributions in the proposed paper. First, we provide a modelling framework for price and load for optimal residential energy scheduling. Second, we concisely present formulation for residential tariff structures and electrical devices based on descriptions found in the literature. Finally, we expand the literature on the implication of pricing mechanisms on REMS and metering. Future work includes the expansion of the model to aggregates of dwellings in order to better evaluate tariff structures and policies.
A Convex Primal Formulation for Convex Hull Pricing

Bowen Hua       Ross Baldick*

May 30, 2016

Abstract

Unit commitment and dispatch of generation in electricity markets involves the ISO sending target quantity instructions and prices to each generator. Ideally, energy prices provide incentives for profit maximizing market participants to comply with efficient commitment and dispatch instructions. Non-convexity of the unit commitment problem prevents this ideal, so that start-up and no-load costs of generation units may not be covered by sales of energy at locational marginal prices. To encourage generators to comply with commitment and dispatch, non-negative profit is guaranteed by the ISO, but this guarantee necessitates non-anonymous uplift payments. Convex hull pricing is a uniform pricing scheme that minimizes uplift payments. The Lagrangian dual problem of the unit commitment problem has been used to determine the convex hull prices. This approach is computationally expensive, however.

We propose a polynomially-solvable primal formulation for the Lagrangian dual problem in which we explicitly describe convex hulls of individual units’ feasible sets and convex envelopes of their cost functions. Our formulation gives exact convex hull prices in the absence of ramping constraints. The exactness is preserved when ancillary services or transmission constraints are considered. A tractable approximation applies when ramping constraints are present. We cast our formulation as a second-order cone program when the cost functions are quadratic, and a linear program when the cost functions are piecewise linear. Numerical tests are conducted on several examples found in the literature.

*The authors are with the Department of Electrical and Computer Engineering, the University of Texas at Austin, Austin, TX 78701 USA (e-mail: bhua@utexas.edu; baldick@ece.utexas.edu). The presenting author is Bowen Hua. A preprint of the full paper can be found at https://arxiv.org/abs/1605.05002.
Abstract

One of the recurring themes in the past few decades of electric grid operation is the need to operate closer to the grid’s physical limits. Pushing back on this need is the desire to operate reliably as well as a lack of computationally efficient tools to optimize electric power flow. Recent and projected increases in intermittent renewable energy generation will make it even more important to operate closer to the grid’s limits. Wind power, for example, is typically generated far away from demand centers and cannot be forecasted with high accuracy. This can create conditions with significantly different system voltage profiles than what is expected, and can result in uneconomic or unreliable operations. We formulate an electric dispatch model that considers changes to voltages in the economic and reliable operation of the grid. Network equations for AC power flow are linearized and included as constraints in a linear program. The resulting constraints are expressed in terms of real and reactive power, which allows the inclusion of voltage, thermal, and D-curve limits. Current practice is to operate the grid more conservatively instead of explicitly modeling these constraints. Once these constraints are explicit, the grid can be operated more economically by operating closer to its physical limits. The proposed model extends the current market optimization model, and additionally does not require advanced solvers in order to be implemented in today’s electricity markets.

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A Simulation Model for Determining Optimal Demand Response Actions: Application to the ERCOT Power Market

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Keywords: Simulation, optimization, demand response, load-shifting

Abstract:
In power markets, there are potential large savings to be made by shifting the load from an hour of high prices to an hour with lower ones. The savings occur because the retail electric provider (REP) buys power when it is less expensive to meet customers’ loads. In addition to shifting the load to a less expensive hour, the recovered load is reduced relative to the original one. This type of direct control demand response (DR) is known as load shifting and is the subject of the current work, in which a DR stochastic optimization model is developed. This model takes into account both load and price uncertainty via Monte Carlo simulation with appropriate fitted probability distributions and determines optimal load-shifting rules based on a set of potential load-shifting decisions. In effect, the model is a stochastic, binary optimization and is solved via enumeration and simulation. The model relies on market settlement price data from ERCOT (Electric Reliability Council of Texas) and uses 6950 households’ loads from a Texas power provider.

A typical summer day for the ERCOT market is modelled where the load is highly correlated with temperature and air conditioning loads. The various DR events include: 1-hour shifts (e.g., hour ending 14 to 15), 2-hour shifts (hours 16, 17 to 18), 3-hour and 4-hour shifts and only the hours ending 14-20 (peak) and 21 (off-peak) examined due to their potential for profit improvement. The model does not consider payback past the first hour following the DR event.

The simulation-optimization results highlight that the REP’s financial risk (conditional value-at-risk) can be greatly improved by proper choice of load-shifting regime (duration of DR event as well as particular hours chosen). The resulting simulated probability distribution for REP profit has a long tail to the left representing the “downside risk” which can be shifted to the right by appropriate DR rules. Besides improving the CVaR, the expected profit can also be increased by appropriate decision strategies. A bi-objective Pareto frontier is generated to highlight the tradeoff between these two competing objectives (CVaR and expected profit). Additionally, an economic analysis is performed to highlight the shadow price of relaxing the maximum number of DR events/maximum number of DR hours.
The Future of Nuclear Power Generation in Europe -
Model Analysis using the dyn-ELMOD Framework

Abstract for TAI (November, 2016)

Clemens Gerbaulet (*), Casimir Lorenz, Pao-Yu Oei, Mario Kendzierski, and Christian von Hirschhausen (TU Berlin, and DIW Berlin)

The nuclear power industry is facing structure change Europe-wide: faced with increasing costs and low-cost alternatives (coal, natural gas, renewables). Some European countries have made concrete provisions to close their nuclear power plants, but the European Commission’s Reference Scenario 2016 forecasts the construction of approx. 100 GW of new nuclear power plants until 2050. Similar questions are ongoing in the US and in other nuclear countries around the world. The paper applies a model developed recently by Gerbaulet and Lorenz (2016), called dynELMOD, to provide scenarios for the future of nuclear energy, and other fuels, for Europe in the mid- to long-term. The dynELMOD energy market model determines the most cost-effective adjustment of energy generation capacities and power plant utilization for every European country in the period 2015 to 2050. This is done given fixed framework conditions such as the power plant fleet, demand development, CO₂ mitigation targets, and development potential of renewable energies with specified investment costs for new capacities and fuel prices for conventional power generation; it can also be used to model transmission requirements, though these are identified on a one-country-one-node basis only.

Preliminary results indicate the key role of two countries, France and the UK: France has started its “transition énergétique” destined to reduce the share of nuclear electricity to 50%, but is pondering a wide range of future energy options; in the UK, much depends on the construction of a French-Chinese reactor for the Hinkley Point C site, which is uncertain for the time being.

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In Search of Adaptive Strategy for Power System Expansion in Bangladesh through Robust Decision Analysis


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Abstract

The objective of this study is to assist the government of Bangladesh to make the decision in power sector expansion in the face of deep uncertainties in the time period through 2030. Robust decision making analysis (RDM) is applied in many issues when facing deep uncertainties in the future. In this study, RDM is used and modified to search for an adaptive strategy that can be implemented by Bangladesh government in power system expansion. The uncertainties in the future mainly encompass the climate change factors and some socio-economic variables such as flood impact and price factor. Based on the uncertainties considered in the study, 200 future states can be determined and plugged into the optimization model of Bangladesh power system. Then, the new build capacity from different fuel type mix can be defined as the strategies for the decision makers. We have 4 metrics to evaluate how well the strategy performs including the percentage of unserved demand, greenhouse gas (GHG) emission, levelized cost of electricity and percentage of unmet reserve. After that, we set thresholds for each metric and PRIM algorithm is utilized to find the robust strategy and its vulnerable future region. Finally, an adaptive strategy is figured out based on the previous steps.
How do price caps in China’s electricity sector impact the economics of coal, power and wind? Potential gains from reforms.

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Abstract

China imposes maximum prices by plant type and region on the electricity that generators sell to utilities. We show the need for subsidies and cross-subsidies due to the price caps on the electricity sector and their effects on the economics of wind power and the need for subsidies in the form of feed-in tariffs. We model the power and coal supply sectors as a Mixed Complementarity Problem (MCP), calibrated to 2012 data. We show that the price caps impose an annual cost of 45 billion RMB, alter the generation and fuel mixes, require subsidies for the market to clear, and do not incentivize adding capacity for a reserve margin. They have cross-sectoral effects and incentivize market concentration so that generators can cross-subsidize power plants. Increasing wind capacity alleviates the distortions due to the price caps when the regulators do not lower the caps when coal prices decrease. The added wind capacity, however, does not have a significant impact on the amount of coal consumed. We also find that the feed-in tariff was priced slightly higher than necessary.

To our knowledge, our study is the first to model the Chinese tariff caps and our representation in the MCP is novel. We connect three different strands of research. First, we develop a model with detailed representations of technologies and regional breakouts for analyzing the Chinese power sector. This approach allows us to address a wide range of policy scenarios, including the sector’s strategic development plan, the costs of policies for meeting emission control targets, and the opportunities for developing interregional integration of electricity markets. Second, since we link the coal sector with the electricity sector, our study relates to the literature examining cross-sectoral interactions of coal and electricity policies. Third, we add to the mixed-complementarity-problem literature, showing how price caps and subsidies can be represented in MCPs.

We examine the following questions:
- How efficient is the current electricity market with price caps compared to a deregulated market?
- What are the effects of the price caps on the utilization and value of existing capacity, investment decisions, energy flows and the development of wind?
- What are the cross-sectoral effects of the existing pricing policy?
- What is the effect of increased wind penetration on the coal and electricity sectors?
All combustion processes create emissions of different types, some are benign but some are harmful to human health. The energy sector relies heavily on combustion of fossil and other types of fuels to fulfill demand for services. Changes in the structure or composition of the energy sector, such as a change in the mix of fuel sources, generation or end use technologies, locations, or operating patterns, can change the types, amounts and regional patterns of emissions. The human health effects of emissions depend on what is being emitted, how much is being emitted and where those emissions are released.

Computer models can be useful when projecting changes in the energy sector over time (energy system models), or when examining the impact of emissions on air quality (fate and transport models).

The National Energy Modeling System (NEMS) is the most detailed model of the US energy system available. It is used by the US Energy Information Agency to produce the Annual Energy Outlook (AEO), a national projection of technology adoption and investment (such as new builds of electric generating plants), and energy use by fuel type and by sector (e.g., industrial, transportation). Thus it could be a powerful tool to analyze changes over time in emissions, air quality and public health. However, there are several challenges with using it to conduct this type of research: NEMS does not calculate all emissions species that are important when considering public health, also NEMS is not granular over space or in time.

Fate and transport models, are used to simulate the transformation (fate) and migration (transport) of emissions and the subsequent air quality in a given region at a given time. These models require highly granular emission data over time and space as input, much more granular than available from energy system models. Therefore, the results from energy system models must be processed and “downscaled” before they can be useful in fate and transport models. This processing has three essential steps: First, emissions not reported by the model must be calculated using information about fuel consumption, conversion technology and emission control equipment. Second, emissions reported for the large geographic regions in the energy system model must be apportioned to the modeling grid employed in the fate and transport model, using a combination of information about population distributions, locations of existing point source and transportation routes, as well as assumptions about where new point sources will be located. Third, emissions reported annually or for only a few time buckets per year, must be apportioned out to hourly values, based on information about typical hourly operation or usage and assumptions about how usage may change in the future.

In this talk I will describe these steps and review the challenges, as well as present some preliminary results from emissions downscaling of AEO cases.
Linear reformulations of the unit commitment problem

Kerstin Daechert, Christoph Weber (Management Science and Energy Economics, University of Duisburg-Essen)

The well-known unit commitment problem determines the cost-optimal commitment of power plants to meet an exogenously given demand while taking certain constraints like maximum capacity, minimum stable operation limit, minimum operation time, minimum downtime etc. into account. The problem is classically formulated as a mixed-integer linear program. However, when applying this MIP model to real-world instances like the German or European electricity market with a one-year optimization horizon some sort of simplification is required to obtain reasonable computational times. Moreover, the units are typically aggregated in this context. Therefore, a linear reformulation of the model seems appropriate. In this talk we compare different linear formulations of the unit commitment problem and discuss which formulation is best suited for our application. We present solutions for a large real-world electricity market model using these reformulations.
Models for co-optimization of demand response and reserve offers in electricity markets

Golbon Zakeri, M. Habibian, A. Downward, M. Anjos, and M. Ferris

We will discuss a number of models that highlight bidding strategies of large consumers of electricity into electricity markets where energy and reserve is co-optimized. We will start by investigating the co-optimized OPF. We then discuss a price taker result for a perfectly competitive large consumer. Subsequently we examine price making models for large consumers who are capable of demand response and reserve offers.
Designing an Energy System based on 100% Renewables in 2050

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Abstract

Currently, around 86% of the world's energy supply is based on fossil fuels and nuclear energy. Burning these fossil fuels emits greenhouse gases, leading to climate change and environmental warming. Hence, there is a need to take a look at the global energy system and its possible realizations towards full decarbonization. In order to do this, we develop a linear cost-optimizing model for the path from 2015 to 2050 in 10 year steps. The model is based on the existing OSeMOSYS (Open Source Energy Modeling System, http://www.osemosys.org/). We aggregated countries into ten geographic regions, calculating energy and resource flows to meet power, heat and transport demands. Final demands and demand profiles for our model stem from the 450ppm scenario of the IEA, resulting in a primary energy demand of 290 EJ in 2050. Time is disaggregated into multiple time slices, modeling seasons and day/night cycles. While being global in scope, the analysis focuses on the results for Europe.

Current results indicate that the share of conventional energy carriers used for power generation was still at 69% in 2020, the year 2030 indicates a strong turning point towards renewable power generation with only about 35% being produced by conventional energy carriers. Europe (and North America) both show strong tendencies towards an early adoption of widespread renewable energies with over 95% of power generation in renewables by 2030. Based on the model calculations, the global energy system towards 2050 mainly relies on wind power (58%), solar power (19%) and biomass (14%). To a smaller degree, hydro, geothermal and concentrated solar power provide energy as well. Because the other two main sources of energy, wind and solar power, produce energy in form of electricity, we observe a strong sector-coupling of the power sector with both the heat and transport sector. In the heating sector, heat pumps and direct heating with electricity convert power into heat. In the transport sector, electricity is directly used in battery electric vehicles and electric rails as well as converted into hydrogen to provide mobility where the direct use of electricity is not possible. Around 66% of the total investment costs occur in the last two modeled periods, 2040 and 2050.
Power Generation Expansion Planning with Multiple Constraints for Sri Lanka

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An electric power system is a dynamic system and the main objective is to maintain the balance between the supply and demand. The planning process of power system is fully coordinated with three main components; generation, transmission and distribution. Generation expansion planning is especially important due to its specific features such as long lead time to provide additional electric energy, high capital investment, long term payback period, and multiple alternatives in supply options. Developing countries further face the challenge of high finance cost, competition for natural resources, limitations for access to technology, social and environment constraints, and high electricity demand growth. The purpose of this study is to apply an optimization methodology based on dynamic programming to develop a long term power generation expansion plan the Sri Lanka which is considered a developing country.

Presently, the power generation in the country consists of 50% renewable energy and 50% oil and coal fired thermal energy. The country has no commercially proven fossil fuel resources and hydro power is the main indigenous power source which provides 40% of total electricity demand. The majority of hydro power generates from the multipurpose reservoir network, where water is also used for irrigation. Water usage according to the irrigation requirements are important since 33% of the population is employed in the agriculture sector. Competition for water is high and individual preferences and objectives of each sector challenges the best usage of the natural resources. The power system experience same daily load profile for the last 25 years which has the characteristics of 40% x peak off peak demand and evening peak demand. This limit the addition of inexpensive base load thermal power generation technologies and absorption of renewable power. Affordability for the state of the art technologies such as smart metering for renewable power absorption is limited in such a developing country.

The government of Sri Lanka developed a power generation expansion plan by optimizing the economic cost of power generation (capital cost, salvage value, fuel cost, fuel inventory, maintenance cost, loss to the economy by not serving the demand) under constraints of reliability and environment sustainability. This study considers the 25 years planning window while accounting for the complexity of adding new power generation facilities. To address demand projection, the initial step of the planning utilizes techniques such as time trend analysis, econometric method, and end use methods. Projected demand growth rate is 5-6% and candidate power supply options are renewable, fossil fuel fired thermal power, and nuclear power (with 16 years lead time). Two reliability criteria are used, as the Loss of Load Probability (LOLP) and the Reserve Margin. Environment emissions are limited for SO₂, NOₓ, CO₂ and particulate matters according to the regulations.

The generation planning is challenging and complex, and it requires the consideration of multiple constraints such as environment, reliability, affordability, and competition for the resources. Stakeholder participation throughout the planning process will be improved for the development of a better plan using mathematical models.

**Keywords:** Demand projection, Economic optimization, Dynamic programming, reliability, environment

**REFERENCES:**
Post-disaster Electric Grid Restoration Resource Allocation

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Abstract

History has shown that electrical power systems whether at the transmission or distribution level can be severely affected by natural disasters. To improve the resiliency of the power grid against such events, system partitioning has been proposed in the literature as part of the restoration process. In this work, we formulate a novel restoration resource allocation model based on a non-classical topology approach that provides a realistic system structure. The proposed model combines topology control, load and generation dispatch along with operation constraints to identify the optimal partitions and generation placements. The number of partitions are further reduced to produce a unified network once more resource become available. Simulation results on test systems show the effectiveness of our approach.

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Shale gas & South Africa’s energy future - too costly too late?

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South Africa faces the challenge of supplying its growing energy demand while simultaneously reducing greenhouse gas emissions. This paper evaluates the effectiveness of shale gas as a measure to reach these aims. We analyze the viability of shale gas development under different economic conditions, evaluate the atmospheric impact of shale gas extraction and quantify the combined effects of shale gas extraction and carbon taxation. For this analysis we develop a linear least cost optimization model of the South African energy system based on MESSAGE, the well known integrated assessment framework for energy systems developed by the International Institute for Applied Systems Analysis (IIASA).

First, we find that shale gas needs to become available at prices below current estimates in order to be competitive with South Africa’s cheap abundant coal reserves. Therefore we presume that the CO2 mitigation potential of shale gas in the South African case is very limited and that shale gas cannot be considered a substitute for an effective climate protection policy. If shale gas would become available at sufficiently low costs, shale gas exploitation in conjunction with a moderate carbon tax of 10 USD/tCO2 to 25 USD/tCO2 could reduce South Africa’s energy related CO2 emissions by up to 15 %. To reach South Africa’s more ambitious climate commitments made at the United Nations climate conference in Paris, the country would however have to implement a higher effective carbon tax of at least 30 USD/tCO2. But such a tax level would at the same time lead to a rapid transition to the use of non-carbon fuels, which again would make shale gas less in demand. However, given that an elevated carbon tax will most likely be introduced gradually rather than overnight, shale gas could stand its ground as a transition fuel on the way to a green energy system.

We conclude that shale gas can, under certain conditions, support the transition towards a low carbon energy system. But, given the limited scope of CO2 emission reductions that can be achieved from a coal-through-gas fuel substitution, it is unclear whether the climatic benefits are large enough to compensate the impact of hydraulic fracturing upon the ecosystem. This topic requires further research as to establish if other natural gas sources might not bring the same benefits while avoiding the disadvantages from the fracking process.
Discretely Constrained MCPs –
Application on a stylized electricity market

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Abstract
Game theoretic applications with discrete constraints can be found across multiple sectors, e.g. in form of binary
decisions. Recent research provides various methods to formulate and solve discretely constrained complement-
tary problems (DC-MCP) by relaxing complementarity, however it remains unclear if and how the solutions re-
fect the economic perspective of traditional, continuous MCPs.

This paper provides insight into different areas of DC-MCPs. First, we look at different solution-methods for
DC-MCPs from the literature and compare them in terms of solutions and usability. The different methods are
applied to a stylized electricity market, including a discrete minimum generation constraint. Second, we explore
the mathematical and economic implications of the solutions towards the topic of equilibria and show that the
traditional methods including discrete variables sometimes prohibit correct solutions in terms of economic sta-
bility. Finally, we propose a method to implement a two-stage DC-MCP, using an upper level service operator
(SO) to find solutions which are in line with the economic definitions of an equilibrium.

We show, from an economic perspective, that when relaxing complementarity a simple minimization does not
necessarily lead to an optimal solution. To find solutions in which no player has an incentive to change strategy,
an additional constraint or an upper-level SO is needed.
Investments in Renewable and Conventional Energy: The Role of Operational Flexibility

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There is an ongoing debate among energy experts on how providing a subsidy for one energy source affects the investment in other sources. To explore this issue, we study capacity investments of a utility firm in renewable and conventional sources. Specifically, conventional sources are categorized into two groups as inflexible (e.g., nuclear and coal-fired plants) and flexible (e.g., natural gas), based on operational flexibility, i.e., whether or not the output of a source can be ramped up or down quickly. We model this problem as a two-stage stochastic program in which the firm first determines the capacity investment levels, followed by the dispatch quantities of energy sources so as to minimize the sum of the investment and generation-related costs. We derive the optimal capacity portfolio and characterize the interactions between renewable and conventional sources. We find that operational flexibility plays a key role in these interactions: renewable and inflexible sources are substitutes, whereas renewable and flexible sources are complements. This result suggests that a subsidy for the nuclear or coal-fired power plants leads to a lower investment level in renewables, whereas a subsidy for the natural gas-fired power plants leads to a higher investment in renewables. We validate this insight by using real electricity generation and demand data from the state of Texas. Finally, we show that a carbon tax leads to a lower renewable investment if the inflexible source is carbon-free nuclear energy.

Keywords: Energy-related Operations, Capacity Investment, Volume Flexibility.
The economics of rate-of-return regulation in the natural gas pipeline industry

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Abstract

The purpose of this paper is to contribute to the analysis of the economics of the gas pipeline industry. We consider a simple point-to-point infrastructure that is provided by a private company that is subject to a traditional rate-of-return regulation. It is envisioned that the installation of the infrastructure could unlock a growing demand for natural gas but the firm is presumed to be myopic and reluctant to build ahead of proven demand.

We address three related questions. First, is it possible to analytically characterize the technology of a natural gas pipeline system? Second, what is the magnitude of the overcapitalization effect (the so-called Averch-Johnson effect) generated by rate of return regulation? Third, is it possible to determine a socially optimal rate of return in that industry, and if yes, at what level?

The contribution of this paper is fourfold. First, we review the detailed engineering equations governing the natural gas pipeline technology and analytically prove that this technology can be approximated by a Cobb-Douglas production function that has two inputs: capital and energy. We then examine the associated long-run cost function, document the magnitude of the increasing returns to scale obtained with that infrastructure and confirm the natural monopolistic nature of that industry.

Second, we analytically characterize the behavior of a monopolistic pipeline operator that is subject to rate of return regulation. The associated market outcomes are systematically compared with the ones obtained under three alternative organizations: (i) an unregulated monopoly, (ii) a social planner that maximizes the net social welfare while ensuring a non-negative economic profit for the pipeline operator, and (iii) the hypothetic case whereby the regulated firm is compelled to use cost-efficient combinations of inputs. The results document the magnitude of the Averch-Johnson effect and its impacts on output, overcapitalization levels, production costs, and net social welfare.

Third, we formulate and analytically solve a bilevel programming problem that models the relations between a welfare-maximizing regulatory agency that decides an allowed rate of return for that activity, and the profit-maximizing firm that designs and operates the infrastructure. We clarify the conditions for the existence of a solution to that problem and discuss the policy implications.

Lastly, the paper considers investment timing considerations. We consider the possibility to observe an ex post demand larger than the one used at the planning stage and examine the implications. We analytically characterize the ex post behavior of the regulated firm and how its output is modified compared to the output that was expected ex ante. Then, the analysis concentrates on the possibility to strategically set ex ante the allowed rate of return so that the generated overcapitalization is aligned with the capital required to achieve ex post cost efficiency (and limited social welfare losses). Useful policy recommendations are derived for the development of gas infrastructures in developing economies.

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Using a rolling-horizon stochastic mixed complementarity equilibrium model to examine the benefits of load shedding strategies

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Abstract

As a result of policies increasing the amount of electricity generated from fluctuating renewable sources in many countries, the requirement for flexibility in the corresponding electricity systems increases. On the demand side, load shedding is one demand response mechanism contributing to an increased flexibility. Traditionally, load shedding was based on rather static or rotational strategies, whereby the system operator chooses the consumers for load shedding. However, ongoing technological developments provide the basis for smarter and more efficient load shedding strategies. We therefore examine the costs and strategies associated with such mechanisms by modelling an electricity market with different types of generators and consumers. Some consumers provide flexibility through load shedding only while others additionally have the ability to generate their own electricity. Focussing on the impacts of how and to whom consumers with own generation ability can supply electricity, the presence of market power and generator uncertainty we propose a rolling horizon stochastic mixed complementarity equilibrium model, where the individual optimisation problems of each player are solved simultaneously and in equilibrium. We find that a non-static strategy reduces consumer costs while allowing consumers to provide own generation to the whole market results in minimal benefits. The presence of market power was found to increase costs to consumers. We also consider the optimal foresight horizon that market players should consider. This novel study finds that the optimal foresight horizon is mainly driven by the daily load structure and, to a lower degree, by the uncertainty of the generators’ availability.

Keywords: Load shedding, demand-side flexibility, rolling horizon, stochastic mixed complementarity

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